531 Rec'd PCT/ 19 DEC 2001

U.S. APPLICATION NO. (If known, see 37 CFR 1.5) 10/019122	INTERNATIONAL APPLICATION NO PCT/EP00/05513	ATTORNEY'S DOCKET NUMBER 11836.0677.NPUS00

17. ☒ The following fees are submitted:

CALCULATIONS PTO USE ONLY

Basic National Fee (37 CFR 1.492(a)(1)-(5)):

Neither international preliminary examination fee (37 CFR 1.482) nor international search fee (37 CFR 1.445(a)(2)) paid to USPTO and International Search Report not prepared by the EPO or JPO $1040.00

International preliminary examination fee (37 CFR 1.482) not paid to USPTO but International Search Report prepared by the EPO or JPO $890.00

International preliminary examination fee (37 CFR 1.482) not paid to USPTO but international search fee (37 CFR 1.445(a)(2)) paid to USPTO $740.00

international preliminary examination fee (37 CFR 1.482) paid to USPTO but all claims did not satisfy provisions of PCT Article 33(1)-(4)......................... $710.00

International preliminary examination fee (37 CFR 1.482) paid to USPTO and all claims satisfied provisions of PCT Article 33(1)-(4) .... $ 100.00

ENTER APPROPRIATE BASIC FEE AMOUNT =				$890.00	
Surcharge of $130.00 for furnishing the oath or declaration later than ☐ 20 ☒ 30 months from the earliest claimed priority date (37 CFR 1.492(e)).				$130.00	
Claims	Number Filed	Number Extra	Rate		
Total Claims	8 - 20 =	0	x $ 18.00	$0.00	
Independent Claims	1 - 3 =	0	x $ 80.00	$0.00	
Multiple dependent claim(s) (if applicable)			+ $270.00	$-0-.00	
TOTAL OF ABOVE CALCULATIONS =				$1020.00	
Reduction by ½ for filing by small entity, if applicable. Verified Small Entity statement must also be filed. (NOTE: 37 CFR 1.9. 1.27, 1.28)				$ .00	
SUBTOTAL =				$1020.00	
Processing fee of $130.00 for furnishing the English translation later than ☐ 20 ☐ 30 months from the earliest claimed priority date (37 CFR 1.492(f)). +				$n/a.00	
TOTAL NATIONAL FEE =				$1020.00	
Fee for recording the enclosed assignment (37 CFR 1.21(h)). The assignment must be accompanied by an appropriate cover sheet (37 CFR 3.28, 3.31). $40.00 per property) +				$ .00	
TOTAL FEES ENCLOSED =				$1020.00	
				Amount to be refunded:	$ .00
				charged	$ .00

a. ☐ A check in the amount of $_____.00 cover the above fees is enclosed.

b. ☒ Please charge as indicated on enclosed FORM 2038 in the amount of $ 1868 to cover the above fees.

c. ☒ The Commissioner is hereby authorized to charge any additional fees which may be required, or credit any overpayment to Deposit Account No. 01-2508/11836.0677. A duplicate copy of this sheet is enclosed.

NOTE: Where an appropriate time limit under 37 CFR 1.494 or 1.495 has not been met, a petition to revive (37 CFR 1.137(a) or (b)) must be filed and granted to restore the application to pending status.

SEND ALL CORRESPONDENCE TO:

Carter J. White
HOWREY SIMON ARNOLD & WHITE LLP
750 Bering Drive
Houston, TX 77057-2198
(713) 787-1400

Carter White
SIGNATURE

Carter J. White
NAME

41,374
REGISTRATION NUMBER

Water based wellbore fluids

The invention relates to wellbore fluids used during a hydrocarbon recovery process, such as drilling, fracturing, gravel packing and wellbore workover. More precisely, the present invention relates to water based fluids.

Wellbore fluids used in the hydrocarbon containing subterranean zones must fulfil besides the usual functions of a drilling fluid also more specific requirements to ensure minimum damage to the formation. The currently available water based drilling fluids are able to ensure minimum damage to the formation and completion due to the selection of the right particle size distribution of the bridging solids, the choice of the fluid loss additive and other components of the fluid.

With standard graded calcium carbonate based drilling fluids and the subsequent filter cake it produces, the initial return permeability may be high. However, the presence of drill-solids can be enough to significantly affect the filter cake behaviour, so reduce the effective permeability of the reservoir and as such a stimulation treatment would be recommended to substantially remove the filter cake.

Furthermore an increasing practice is the drilling of unconsolidated sand reservoirs, where there is a requirement for sand control techniques. One common practice is to use gravel packs. Unfortunately the gravel pack tends to exacerbate the changes in filter cake behaviour, the formation damage level and so the effective permeability, even with clay-free wellbore fluid. This is further exacerbated with the drill-solid contaminated well-bore fluid where the return permeability can be zero up to differential pressures of 400kPa.

Any attempt to remove the drill-solid from the mud with the technique commonly used on the surface (e.g. sieves, hydrocyclones, centrifuges) would inevitably remove as well at least partially the bridging solids and so affect not only their concentration but also their particle size distribution in the mud. The fluid potential for minimal formation damage achieved by the right bridging solid concentration and especially particle size distribution would therefore be detrimentally affected.

In summary the ultimate productivity of a well can be strongly impacted by the damaging potential of the well-bore fluid, the detrimental effect of drill-solids to filter cake performance and the complication of the compatibility of well bore fluid components with the sand control techniques. This means that there will be in many instances a requirement for stimulation of the filter cake, where the stimulation process in itself can be ultimately damaging to the completion or reservoir. Accordingly there is a need for a well-bore fluid that will be non-damaging to the hydrocarbon formation and the sand control techniques and also not require any external stimulation process to allow hydrocarbons to flow.

The use of wellbore fluids for conducting various operations in oil and gas wells which contact a producing formation are well known. Drill-in fluids are used when initially drilling into producing formations. Completion fluids can be used when conducting various completion operations in the producing formations. Workover fluids are utilized when conducting remedial operations to the wellbore and hardware.

One of the most important function of these fluids is to seal off the face of the wellbore so that excessive fluid is not lost to the formation, so reducing the potential for formation damage and hence ensuring a better reservoir productivity.

Many concepts have been proposed for contacting the producing zone of oil and gas wells.

These fluids generally contain polymeric viscosifiers such as polysaccharides, polymeric fluid loss control additives such as lignosulfonates or polysaccharides and bridging solids.

Some provide better fluid loss reducing properties by providing new modifications to the fluid loss additive (e.g. US4652384, US5851959), by using pore blocking water swellable gel (e.g. WO9702330, US4526240), by replacing the bridging solids (e.g. US5228524, US5504062, EP0691454, US3878141, US3785438, GB2120302, US3788406, GB570329) or by using a sealant composition (e.g. EP0899317, US5529123). GB2120302 includes the use of hydrophobially coated glass particles to improve fluid loss properties. It has also been proposed to use a well drilling system that generate an easily removeable filter cake or a treatment to remove the filter cake (e.g. EP0672740, US5783527, WO9805734).

In most of the above mentioned documents, the hydrocarbon recovery process include a preliminary filter cake treatment or removal to achieve a better productivity. Some inventions mentioned include the use of oil wettable, hydrophobic or hydrophobically modified bridging solids or components. However their intention is to improve fluid loss properties or create a new type of gravel pack.

A main object of the present invention is a water based wellbore fluid comprising a fluid loss additive and a bridging material that are hydrophobic in nature, hydrophobically modified or oil wettable. Wellbore fluids are referred to as mud, drill fluid, drill-in fluid, completion fluid, workover fluid or kill fluid.

The concept behind the present invention is to provide a water based drilling fluid system which generates an active filter cake. Whereby the active filter cake once formed is impermeable to an aqueous phase, thus reducing fluid loss and ensuring reduced damage to the formation, yet simultaneously is permeable to the back flow of hydrocarbons during a hydrocarbon recovery process.

The permeability of the filter cake to hydrocarbons does not rely on the presence of oil soluble material as constituent but on the presence of constituents reducing the interfacial tension to hydrocarbons enabling the creation of paths for hydrocarbons to flow through the filter cake. In this manner the filter

The bridging solid of the present invention may also be constituted of a hydrophobically coated substrate selected among The substrate for the hydrophobic coating is selected among carbonates such as calcium carbonates, zinc carbonates, barium carbonates, coated metal oxide such as hematite, ilmenite, magnesium oxide or other particles such as barite, silica particles, clay particles, microspheres.

The hydrophobic coating is achieved by adsorption of substances onto the surface of a particle or molecule by physisorption or chemical reactions with reactive groups that are present on the surface of this particle or molecule. Examples for such substances are selected among fatty oils, fatty acids, fatty esters, carboxylated, sulfonated, sulfated, phosphonated hydrophobic material, surfactants that would generate a hydrophobic coating, organosilane grafting agents. Those substances introduce alkylsilyl groups or hydrocarbon groups like alkyl groups, especially of long chain onto the surface of the substrate. Coating processes or examples are described in WO9916834, EP0826414, US5183710, EP0606174.

These and other features of the invention will become appreciated and understood by those skilled in the art from the detailed description of the following examples.

Preparation and dynamic ageing (Hot rolling) of muds

The well drilling fluids were prepared according to the following procedure.

1. The brine phase including water as base fluid, salts, a biocide and an antifoaming agent was prepared using an Heidolph paddle mixer.

2. A vortex is created with the paddle mixer to add the polymers (viscosifier, fluid loss additive...) slowly into the brine phase, ensuring that all polymer has completely dispersed. Mixing is continued for a further 30 min. The mixer speed is readjusted as necessary.

3. Other powdered additives (carbonates, clays, magnesium oxide for pH adjustment...) are slowly added into the vortex and mixted for a further 15 min.

4. The mixture is transferred to a Silverson LR2 mixer and mixed at 6000 rpm for 5 minutes.

5. The mixture is transferred back to the Heidolph and mixed for a further 10 minutes. The pH and rheological properties are measured.

Dynamic ageing was carried out by hot rolling the fluids in cells pressurised at 250 psi with nitrogen in an oven for 16 hours. After cooling, the muds were homogenised with a Heidolph paddle mixer for 10 min and the pH and rheological properties were measured. For all formulations a pH in the range 9-10 was used.

Rheology before (BHR) and after hot rolling (AHR)

The measurements were performed at 120°F (49°C) with a 6 speed Fann rheometer BHR (before hot rolling) and AHR (after hot rolling). The rheological properties of the drilling fluids are described by the plastic viscosity in centipoise PV (based on the reading at 600 rpm and 300rpm) and the yield point in pounds per 100 square feet YP. The gel strengths are evaluated by the 10 second and 10 minute gel strengths in pounds per 100 square feet.

HPHT fluid loss

The HPHT spurt loss after 20 sec. and HPHT Fluid-Loss after 16hrs were obtained during the formation damage study when forming the filter-cake on a formation core (filtration area 5.06 cm^2 and length 3cm) or aloxite ceramic disc, (filtration area: 23.8 cm^2 and length 0.6cm).

Formation damage studies

Formation damage is defined as any process that impairs the permeability of reservoir formations to the extent that hydrocarbon production in wells is reduced. Formation damage can occur at all stages of well construction, completion, workover or during production.

1. Experimental set-up

The basis of measuring formation damage is the measurement of the permeability of a core of formation (or a synthetic ceramic disc simulating the formation) to the flow of kerosene (simulating the hydrocarbons) before and after a drilling fluid has been filtered through it. The measurement of the flow rate of kerosene is based on the logging of the flow rate of kerosene (in ml/s) at equilibrium through a core (or disc) of known diameter and length. From the Darcy equation below we are able to calculate the permeability of the core (K) in Darcy : $K = (Q\ \mu\ L) / (DP\ .\ A)$, where Q is the rate of kerosene flow ml/s, μ is the fluid viscosity of the kerosene in centiPoise, L is the length of the core or disc (cm), DP is the pressure drop across the core or disc (atmospheres), A is the surface area of the core (cm^2)

In the described examples, the flow of kerosene was carried out typically at 80°C. The core (or disc) is mounted at one end of a double ended HPHT cell, with the kerosene flowing into the cell filled with kerosene or the packing simulation saturated with brine above the core (or disc). The kerosene displaces rapidly the brine phase and overflows through a top valve into the beaker.

The kerosene is transported under pressure from a cylinder into the reservoir. The kerosene is then passed vertically upwards through a heating jacket to preheat it prior to entering the cell which is also heated. Pressure is regulated for stable kerosene flows through the core (or discs).

4. Return permeability

To simulate standalone completions in consolidated formations (stable holes), the cell was filled with fresh kerosene and the formation damage cell was reassembled. Return permeabilities were carried out in an identical fashion to those for the initial permeability measurements. The flow back is carried out at constant differential pressure. The differential pressure is increased stepwise until flow is initiated. The differential pressure at which the flow starts is referred in the present invention to the Flow Initiation Pressure (FIP).

To simulate gravel packed wells, a sand pack was used. A sufficient volume of a 3% potassium chloride brine is placed above the filter cake, the cell is filled by pouring and packing the sand to fill the cell (up to the top). If necessary more brine is added to allow saturation and tight packing of the sand. The cell is then reassembled, with the 45-micron mesh size screen between the gravel-pack and the top lid of the cell.

Example 1

The following base formulation 1 was mixed according to the general procedure described above and subsequently dynamically heat aged at 80°C for 16hours. It represents the case of a standard calcium carbonate reservoir fluid currently available on the market for most reservoir drilling applications.

Formulation 1 has a density of 1.17 g/cm^3 (9.8 ppg or pounds per gallon) and comprises Brine NaCl 6.9wt.%, KCl 4wt.% in fresh water; Biocide 0.00057 g/cm^3 (0.2ppb (pounds per barrel of 42 gallon); an antifoamer 0.2ppb; Fluid Loss Additive (starch) 0.0142 g/cm^3 (5 ppb); Viscosifier (scleroglucan) 0.0037 g/cm^3 (1.3 ppb); Bridging material (standard calcium carbonate) 0.1283 g/cm^3 (45ppb); pH control additive (magnesium oxide) 0.000856 g/cm^3 (0.3ppb).

Formulation 2 is identical to formulation1 but further contains 0.042786 g/cm^3 (15ppb) of drill-solids (clay).

Example 1 illustrates the background for this invention. It shows the adverse effect of clay added to the standard calcium carbonate formulation on the return permeability for a standalone simulated well. A sandstone Clashach core of initial permeability 750mD is used. Filtration is carried out for 16 hours at 80°C and differential pressure of 3.447 MPa (500 psi, pounds per square inch). The following rheological properties AHR at 48.88°C (120F) and percentage return permeabilities at 80°C after filtration were measured.

	Standalone simulated well	
	Formulation 1	Formulation 2
Rheology: PV/YP	10/20	20/13
Gels: 10s./10 min.	10/12	4/8
HTHT@80°C -500 psi	6ml (32ml)*	7.5ml (27ml)*
Return Permeability	96%	64%

()*for a 60 micron aloxite disc

Example 2

Example 2 illustrates the background for this invention. It shows the effect of clay added to the standard calcium carbonate formulation on the return permeability for a gravel packed simulated well. The presence of the gravel pack reduces drastically the back flow of hydrocarbons.

A 60 microns aloxite disc, with a 20/40 (0.425 to 0.85 mm sized sand). sand pack of is used. Filtration is carried out for 16hours at 80°C and differential pressure of 500 psi.

	20/40 Gravel packed simulated well	
	Formulation 1	Formulation 2
HTHT@80°C-500 psi	31ml	28ml
Return Permeability	10%	0%

Example 3

Example 3 illustrates the background for this invention. It shows the effect of temperature on the return permeability for a gravel packed simulated well and formulation 2.

A 60 microns aloxite disc, with a 12/20 sand pack is used. A 12/20 sand is more permeable than a 20/40 sand (0.425 to 0.85 mm sized sand). Filtration is carried out for 16hours at various temperatures and differential pressure of 500 psi. The following rheological properties AHR at the filtration temperature (when lower than 120F) or at 120F (when higher than 120F) and percentage return permeabilities after filtration at this temperature were measured.

Example 7 shows the effect of using as bridging solids a blend of hydrophobically coated and standard non-coated calcium carbonate on the return permeability for the gravel packed simulated well. A 60 microns aloxite disc and sand pack 20/40 is used. Filtration is carried out at 80°C and differential pressure of 500 psi.

	Gravel pack 20/40 simulated well Formulation 3
Rheology: PV/YP	24/25
Gels: 10s./10 min.	8/27
HTHT@ 80°C -500 psi	26
Return Permeability	0%

Example 8

The following base formulation 4 was mixed according to the general procedure described above and subsequently dynamically heat aged at 80°C for 16 hours.

Formulation 4 has a density of 9.8 ppg (pounds per gallon) and comprises: Brine NaCl 6.9wt.%, KCl 4wt.% in fresh water; Biocide 0.2ppb (pounds per barrel); an antifoamer 0.2ppb; Fluid Loss Additive (hydrophobically modified starch) 8 ppb; Viscosifier (scleroglucan) 2 ppb; Bridging material (standard calcium carbonate) 45ppb; Drilling solids (clay) 15ppb; pH control additive (magnesium oxide) 0.3ppb.

Example 8 shows the effect of using as Fluid Loss Additive a hydrophobically modified starch on the return permeability for the gravel packed simulated well. A 60 microns aloxite disc and sand pack 20/40 of is used. Filtration is carried out at 80°C and differential pressure of 500 psi.

	Gravel pack 20/40 simulated well Formulation 4
Rheology: PV/YP	19/16
Gels: 10s./10 min.	5/9
HTHT@80°C -500 psi	21ml
Return Permeability	0%

Example 9

The following base formulation 5 and 6 were mixed according to the general procedure described above and subsequently dynamically heat aged at 80°C for 16 hours. The formulation includes the combination of a coated calcium carbonate and a hydrophobically modified starch and drilling solids (clay).

Formulation 5 has a density of 9.8 ppg (pounds per gallon) and comprises: Brine NaCl 6.9wt.%, KCl 4wt.% in fresh water; Biocide 0.2ppb (pounds per barrel); an antifoamer 0.2ppb; Fluid Loss Additive (hydrophobically modified starch) 8 ppb; Viscosifier (scleroglucan) 2 ppb; Bridging material (hydrophobically coated calcium carbonate / standard calcium carbonate) 18ppb / 27ppb) 45ppb; Drilling solids (clay) 15ppb; pH control additive (magnesium oxide) 0.3ppb.

Formulation 6 is the same as formulation 5 except that the bridging agent comprises 27ppb of hydrophobically coated calcium carbonate and 18ppb of standard calcium carbonate.

Example 9 shows the beneficial effect of the coated calcium carbonate and hydrophobically modified starch on the return permeability in formulation 5 for the gravel packed simulated well. A 60 microns aloxite disc and sand pack 20/40 are used. Filtration is carried out at 80°C and differential pressure of 500 psi.

The following rheological properties AHR at 120F and percentage return permeabilities at 80°C after filtration were measured.

	Gravel pack 20/40 simulated well	
	Formulation 5	Formulation 6
Rheology: PV/YP	20/20	21/22
Gels: 10s./10 min.	5/18	6/12
HTHT@80°C-500 psi	20ml	24ml
Return Permeability	33%	15%

Formulation 6 shows the effect of a change in ratio for the bridging solids in formulation 3 on the return permeability for the gravel packed simulated well.

Example 10

Example 10 exemplifies the present invention. It shows a minimal effect of a change in the brine phase in formulation 5 on the return permeability for the gravel packed simulated well. A 60 microns aloxite disc and sand pack 20/40 are used. Filtration is carried out at 80°C and differential pressure of 500 psi.

gravel packed well. Example 5 and 6 show that changing the brine phase or the type of viscosifier in a standard calcium carbonate drilling fluid has no effect on the return permeability of a simulated gravel packed well.

The disclosed drilling fluid system fulfils the usual functions of a conventional drilling fluid. The rheological properties of the drilling fluids of the present invention are perfectly acceptable.

Examples 9-11 describe the performance of the present invention in unfavourable scenarios in which the well is gravel packed and the drilling fluid contaminated by a substantial amount of drill-solids (clay). Example 9 illustrates the present invention with the combination of a hydrophobically coated calcium carbonate and a hydrophobically modified starch. The coated calcium carbonate is used in a blend with non coated calcium carbonate. The example shows the effect of a different ratio between coated and non-coated calcium carbonate on the return permeability. The performance of the drilling system in generating an active filter cake is not improved in this example by an increased amount of coated material. When using a blend of calcium carbonates, the success relies also on the choice of the right particle size distributions of both coated and non-coated components. A change of the ratio coated/non-coated calcium carbonate also affects in this example the overall particle size distribution.

Example 7 illustrates that the use of an oil wettable bridging material alone is not enough for getting return permeability. On the other hand example 8 illustrates that the use of a hydrophobically modified starch alone is not enough either for getting return permeabilty. The combination of both a modified starch and modified calcium carbonate is therefore a requirement to observe return permeability.

Example 10 demonstrates the performance of the present invention in combination with different brine phases.

In example 11, the performance of the active filter cake is enhanced by adding 3%v/v of a lubricant to a formulation of the present invention. The lubricant as a source of hydrophobic sites and because of its emulsifying properties lowering the yield strength of the filter cake contributes to the performance of the active filter cake.

Claims

1. A water based wellbore fluid comprising a fluid loss additive and a bridging material that are hydrophobic in nature, hydrophobically modified or oil wettable.

2. A fluid according to claim 1, wherein said fluid loss additive is selected from hydrophobically modified starch, polyanionic cellulose, carboxymethylcellulose, hydrophobically modified synthetic polymers e.g. poly-hydroxypropylmethacrylate.

3. A fluid according to claim 2 wherein said starch is a polymerised starch or a starch modified by hydroxymethylation, hydroxypropylation, by other hydroxyalkylations or by crosslinking reactions using agents such as phosphorous oxychloride, epichlohydrin, cyanuric chloride, formaldehyde or others.

4. A fluid according to claim 1, wherein said bridging solid is selected from hydrophobically modified inorganic salts, hydrophobic or hydrophobically modified inorganic or organic material.

5. A fluid according to claim 4, wherein said inorganic salts or inorganic material are selected among hydrophobically coated calcium carbonates, zinc carbonates, barium carbonates, hematite, ilmenite, magnesium oxide, barite, silica particles, clay particles, microspheres.

6. A fluid according to claim 5, wherein the hydrophobic coating is selected from fatty oils, fatty acid, fatty esters, carboxylated hydrophobic material or any surfactants that would generate a hydrophobic coating.

7. A fluid according to claim 1 wherein the bridging agent is a ground crystalline material of melting point over 80°C, preferably over 10°C which is readily soluble in produced hydrocarbons such as crude oil and lighter condensates and which exhibits a molecular weight of less than 1000, and preferably less than 650.

8. A fluid according to claim 7, wherein said bridging agent is selected from 1-S-endo-Borneol, camphor, beta carotene, lycophene, cholesterol, lanosterol, agnosterol.

9. Use of the wellbore fluid according to any of claims 1 to 8 as a drilling fluids.

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PATENT & TRADEMARK OFFICE

DECLARATION FOR PATENT APPLICATION AND POWER OF ATTORNEY

As a below named inventor, I hereby declare that:

My residence, Mailing address and citizenship are as stated below next to my name,

I (we) believe we are the original, first and joint inventor of the subject matter which is claimed and for which a patent is sought on the invention entitled

WATER BASED WELLBORE FLUID

the specification of which

(Check one) ☐ is attached hereto.

☒ was filed December 19, 2001 as U. S. Application Serial No. 10/019,122 corresponding to International Application No. PCT/EP00/05513 filed on June 13, 2000

I (we) hereby state that we have reviewed and understand the contents of the above identified specification, including the claims, as amended by any amendment referred to above.

I (we) acknowledge the duty to disclose information which is material to the examination of this application in accordance with Title 37, Code of Federal Regulations, §1.56(a).

☒ I (we) hereby claim foreign priority benefits under Title 35, United States Code, §119 of any foreign application(s) for patent or inventor's certificate listed below and have also identified below any foreign application for patent or inventor's certificate having a filing date before that of the application on which priority is claimed:

Prior Foreign Application(s):

(Number)	(Country)	(Day/Month/Year Filed)	Priority Claimed Yes	Priority Claimed No
9914351.3	GB	06/18/1999	☒	☐
PCT/EP00/05513	EP	06/13/2000	☒	☐

☐ I (we) hereby claim the benefit under Title 35, United States Code, §120 of any United States application(s) listed below and, insofar as the subject matter of each of the claims of this application is not disclosed in the prior United States application in the manner provided by the first paragraph of Title 35, United States Code, §112, I (we) acknowledge the duty to disclose material information as defined in Title 37, Code of Federal Regulations, §1.56(a) which

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DECLARATION FOR PATENT APPLICATION AND POWER OF ATTORNEY

As a below named inventor, I hereby declare that:

My residence, Mailing address and citizenship are as stated below next to my name,

I (we) believe we are the original, first and joint inventor of the subject matter which is claimed and for which a patent is sought on the invention entitled

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Prior Foreign Application(s):

(Number)	(Country)	(Day/Month/Year Filed)	Priority Claimed Yes	No
9914351.3	GB	06/18/1999	☒	☐
PCT/EP00/05513	EP	06/13/2000	☒	☐

☐ I (we) hereby claim the benefit under Title 35, United States Code, §120 of any United States application(s) listed below and, insofar as the subject matter of each of the claims of this application is not disclosed in the prior United States application in the manner provided by the first paragraph of Title 35, United States Code, §112, I (we) acknowledge the duty to disclose material information as defined in Title 37, Code of Federal Regulations, §1.56(a) which

occurred between the filing date of the prior application and the national or PCT international filing date of this application:

(Application Serial No.)	(Filing Date)	(Status) (Patented, Pending, Abandoned)
(Application Serial No.)	(Filing Date)	(Status) (Patented, Pending, Abandoned)
(Application Serial No.)	(Filing Date)	(Status) (Patented, Pending, Abandoned)
(Application Serial No.)	(Filing Date)	(Status) (Patented, Pending, Abandoned)

I (we) hereby appoint the following as our representative(s) to prosecute this application and to transact all business in the Patent and Trademark Office connected therewith: **STEPHEN H. CAGLE,** Attorney (Reg. No. 26,445), **PATRICIA A. KAMMERER,** Attorney (Reg. No. 29,775), **CRAIG M. LUNDELL,** Attorney (Reg. No. 30,284), **JANELLE D. WAACK,** Attorney (Reg. No. 36,300), **CARTER J. WHITE,** Attorney (Reg. No. 41,374), and **ROBERT P. AUERBACH,** Agent (Reg. No. 46,525) each an attorney or agent with the law firm of HOWREY, SIMON, ARNOLD, & WHITE, LLP as its attorney or agent so long as they remain with such law firm.

Address all telephone calls to: at telephone No. (713) 268-1372	Carter J. White
Address all correspondence to:	Customer No. 27551 HOWREY, SIMON, ARNOLD, & WHITE 750 Bering Dr. Houston, TX 77057

I (we) hereby declare that all statements made herein of our own knowledge are true and that all statements made on information and belief are believed to be true; and further that these statements were made with the knowledge that willful false statements and the like so made are punishable by fine or imprisonment, or both, under §1001 of Title 18 of the United States Code and that such willful false statements may jeopardize the validity of the application or any patent issued thereon.

04-12-02 JC02 Rec'd PCT/PTO 11 APR 2002

HOWREY SIMON ARNOLD & WHITE HOWREY LLP ATTORNEYS AT LAW

750 BERING DRIVE
HOUSTON, TX 77057-2198
PHONE 713.787.1400
FAX 713 787.1440
A LIMITED LIABILITY PARTNERSHIP

#6

IN THE UNITED STATES PATENT AND TRADEMARK OFFICE

OIPE JC103 APR 11 2002 PATENT & TRADEMARK OFFICE

In re Application of:
BRAND, Fabien et al.

Application No.: 10/019,122

Confirmation No.: 8280

Filing Date: December 19, 2001

Group Art Unit: NA

Examiner: NA

Atty. Dkt. No.: 11836.0677.NPUS00

For: WATER BASED WELLBORE FLUID

PRELIMINARY AMENDMENT

Commissioner for Patents
Washington, D.C. 20231

CERTIFICATE OF EXPRESS MAIL

NUMBER EL830941145US

DATE OF DEPOSIT 4/11/02

I hereby certify that this paper or fee is being deposited with the United States Postal Service "EXPRESS MAIL POST OFFICE TO ADDRESSEE" service under 37 C F.R. 1.10 on the date indicated above and is addressed to: Commissioner for Patents, Washington, D.C 20231

Cynthia A. Levin
Signature

Before undertaking the examination of the above noted application, Applicants hereby request the following:

IN THE SPECIFICATION:

Please add the following paragraph before the first line of the specification:

This is the U.S. National Phase (35 U.S.C. § 371) of International Patent Application No. PCT/EP00/05513, filed June 13, 2000, which claims priority under Paris Convention Article 4 to GB 9914351.3, filed June 18, 1999.

IN THE CLAIMS:

Please amend the claims as follows:

2. (Amended) A fluid according to claim 1, wherein said fluid loss additive is selected from the group consisting of hydrophobically modified starch, polyanionic cellulose, carboxymethylcellulose, or hydrophobically modified synthetic polymers.

11. (New) A method of fracturing or gravel packing a wellbore using a water based wellbore fluid comprising a fluid loss additive and a bridging material that are hydrophobic in nature, hydrophobically modified, or oil wettable.

12. (New) The fluid according to claim 2, wherein the hydrophobically modified sythetic polymer is poly-hydroxypropylmethacrylate.

13. (New) The fluid according to claim 3, wherein the crosslinking reaction agents are phosphorus oxychloride, epichlohydrin, cyanuric chloride, or formaldehyde.

14. (New) The fluid according to claim 6, wherein the hydrophobic coating is sulfanated, sulfated, or phosphonated hydrophobic material, surfactants that would generate a hydrophobic coating, or organosilane grafting agents.

15. (New) The fluid according to claim 7, wherein the bridging agent is readily soluble in crude oil or lighter condensates.

<u>REMARKS REGARDING AMENDMENTS:</u>

Applicant respectfully submits that no new matter is introduced by the proposed amendments to the claims. These amendments are not meant to narrow the scope of the claims. Because the initial claims were filed in a WIPO application, these amendments are made to place the claims into conformance with proper US practice.

Support for the above amendments to the claims can be found in the original specification as filed in the following locations:

CLAIMS Showing Amendments of Preliminary Amendment

WHAT IS CLAIMED IS:

1. A water based wellbore fluid comprising a fluid loss additive and a bridging material that are hydrophobic in nature, hydrophobically modified or oil wettable.

2. (Amended) A fluid according to claim 1, wherein said fluid loss additive is selected from the group consisting of hydrophobically modified starch, polyanionic cellulose, carboxymethylcellulose, or hydrophobically modified synthetic polymers. ~~e.g. poly-hydroxypropylmethacrylate.~~

3. (Amended) A fluid according to claim 2 wherein said starch is a polymerised starch or a starch modified by hydroxymethylation, hydroxypropylation, by other hydroxyalkylations or by crosslinking reactions. ~~using agents such as phosphorous oxychloride, epichlohydrin, cyanuric chloride, formaldehyde or others.~~

4. (Amended) A fluid according to claim 1, wherein said bridging solid is selected from the group consisting of hydrophobically modified inorganic salts, or hydrophobic or hydrophobically modified inorganic or organic material.

5. (Amended) A fluid according to claim 4, wherein said inorganic salts or inorganic material are selected ~~among~~ from the group consisting of hydrophobically coated calcium carbonates, zinc carbonates, barium carbonates, hematite, ilmenite, magnesium oxide, barite, silica particles, clay particles, or microspheres.

6. (Amended) A fluid according to claim 5, wherein the hydrophobic coating is selected from the group consisting of fatty oils, fatty acid, fatty esters, carboxylated hydrophobic material. ~~or any surfactants that would generate a hydrophobic coating.~~

7. (Amended) A fluid according to claim 1 wherein the bridging agent is a ground crystalline material of melting point over 80°C, preferably over 10°C which is readily

Specification Amendment of Preliminary Amendment

This is the U.S. National Phase (35 U.S.C. § 371) of International Patent Application No. PCT/EP00/05513, filed June 13, 2000, which claims priority under Paris Convention Article 4 to GB 9914351.3, filed June 18, 1999.